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Energy Procedia 37 (2013) 2245– 2255

Energy Procedia

GHGT-11

High Efficiency Integrated Gasification Combined Cycle with Carbon Capture via technology advancements and improved heat integration

Suzanne Ferguson[a]*, Geoff Skinner[a], Jaco Schieke[a], Kwi-Cheng Lee[b], Eva van Dorst[b]

[a]*Foster Wheeler, Shinfield Park, Reading, RG2 9FW, UK*
[b]*Shell Global Solutions International B.V., Carel van Bylandtlaan 16, 2596 HR The Hague, The Netherlands*

Abstract

Adding CO_2 capture to fossil-fuelled power generation results in significant plant efficiency penalties, impacting the performance and economics of the plant. However, many of the public domain studies do not consider technology advancements and optimal heat and power integration. This paper evaluates the efficiency impact of improvements in technology selection, energy recovery and heat integration on the overall thermal efficiency of IGCC schemes with pre-combustion CO_2 capture.

A previous study[1] has shown that the application of emerging or newer technologies and improved process/heat integration to coal-based integrated gasification combined cycle (IGCC) with carbon capture could achieve a cumulative efficiency improvement of more than six percentage points when compared with a current design. This paper looks in more detail at how some of these savings can be achieved and identifies improvements which could be achieved in the near term. In particular, the application of a modified shift system, Thiopaq O&G sulphur removal technology and a novel CO_2 wash system have been included in the scope. (For oil and gas applications, the Thiopaq O&G process is licensed by Paqell BV, a joint-venture company of Shell Global Solutions International B.V. and Paques BV).

Keywords: IGCC; High Efficiency; Integration; Carbon Capture

* Corresponding author. Tel.: +44-118-913-4521; fax: +44-118-913-2333.
E-mail address: Suzanne_ferguson@fwuk.fwc.com.

1876-6102
doi:10.1016/j.egypro.2013.06.105

1. Introduction

One emerging technology, or set of technologies, that has been proposed to mitigate future CO_2 emissions is carbon capture and storage (CCS).

Carbon capture can be applied to oil-, coal- and natural gas-based electricity generation, and there are three process routes that can be considered. These are:

- pre-combustion capture
- post-combustion capture
- oxyfuel combustion.

In a previous paper[1] Foster Wheeler investigated areas in which significant improvements to the efficiency of carbon capture power generation schemes were anticipated for the near- and mid-term time frames, and quantified their impact on the overall efficiency of a plant with carbon capture.

For the IGCC flow scheme with carbon capture it was shown that improvements to the gasification, gas turbine, CO_2 compression and air separation unit (ASU) power loads could be expected to achieve an overall efficiency improvement of six percentage points compared to the current typical IGCC base case. This translated to an increased net power output of nearly 14%.

This paper focuses on low-carbon power generation using an IGCC flow scheme with pre-combustion carbon capture, looking in particular at those improvements which could be applied immediately to new plant designs.

The scope of the design performance includes key offsites and utilities, as well as compression and drying the CO_2, ready for transportation at 150 barg to a suitable storage location or for use for enhanced oil recovery.

2. IGCC Base Case

In order to demonstrate the significance of these improvements, it is helpful to compare the proposed new scheme with a current typical base case IGCC design with carbon capture, as shown in the following block flow diagram (Figure 1):

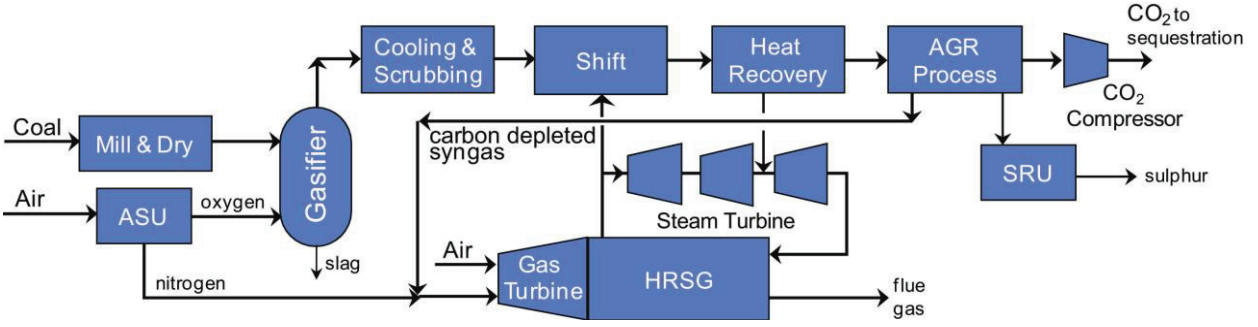

Figure 1: IGCC Base Case - Simplified Flow Scheme

The IGCC plant with carbon capture comprises two gasification lines supplied by a common ASU, two GE F-class gas turbines with heat recovery steam generators (HRSGs) and a common steam turbine.

The conventional, non-integrated ASU supplies oxygen to the gasifiers and sulphur recovery unit and also supplies nitrogen for coal conveying and for dilution of hydrogen-rich, CO_2-depleted gas turbine fuel gas.

In each gasification line coal is milled and dried and fed to an entrained-flow gasifier. The product gas flows through heat recovery with steam generation, particulate removal filtration, quench scrubbing, sour CO shift (which also performs COS hydrolysis) and syngas cooling with heat recovery. A selective DEPG (polyethylene glycol dimethyl ether) unit first removes hydrogen sulphide (H_2S) and then CO_2. The H_2S-rich stream is treated in a Claus sulphur removal unit (SRU) with tail gas treating unit, while the CO_2-rich stream is dehydrated and compressed to 150 barg for export to storage. The hydrogen-rich CO_2-depleted fuel gas stream from the DEPG unit is diluted with nitrogen before combustion in the gas turbines.

3. Improved IGCC with CCS Flow Scheme

The improved flow scheme proposed in this paper can be broken down into a number of sections. Each of these is described below, identifying the changes from the base case.

3.1. Gasifier

No changes were made to this unit compared with the base case, with the exception of minor changes to the conditions and relative quantities of HP and MP steam generated. A flow diagram of the unit is provided below (Figure 2):

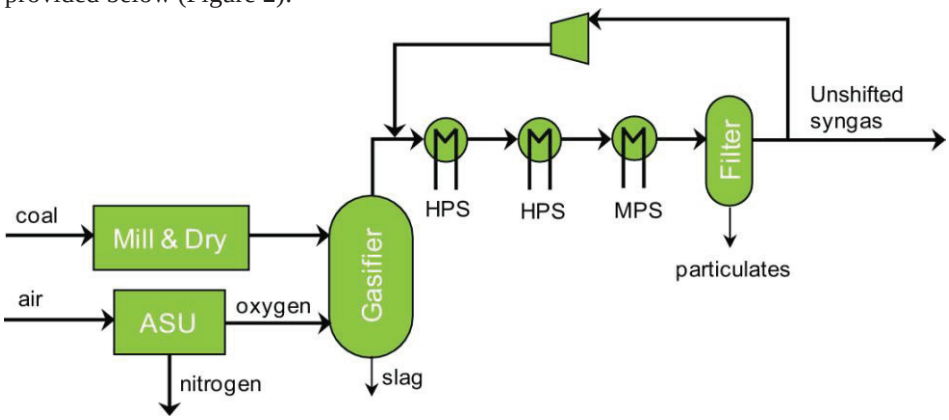

Figure 2: Gasification Unit

3.2. CO Shift

The base case incorporated a three-stage shift process with steam generation/boiler feedwater heating between each reactor. The new scheme uses an improved low steam:dry gas sour shift catalyst (e.g. Qingdao catalyst) in a two-converter configuration. The second converter is provided with internal cooling as developed by Ammonia Casale, so as to give a near-isothermal temperature profile. Heat recovered within the CO shift unit and from the cold end of the HRSGs has been used to enhance

saturation of the CO shift unit feed gas. As a result of these modifications, the demand for external medium pressure steam for the shift is much lower in the new scheme than in the base case. The revised arrangement (Figure 3) of the CO shift and syngas heat recovery system is also less complex than in the base case.

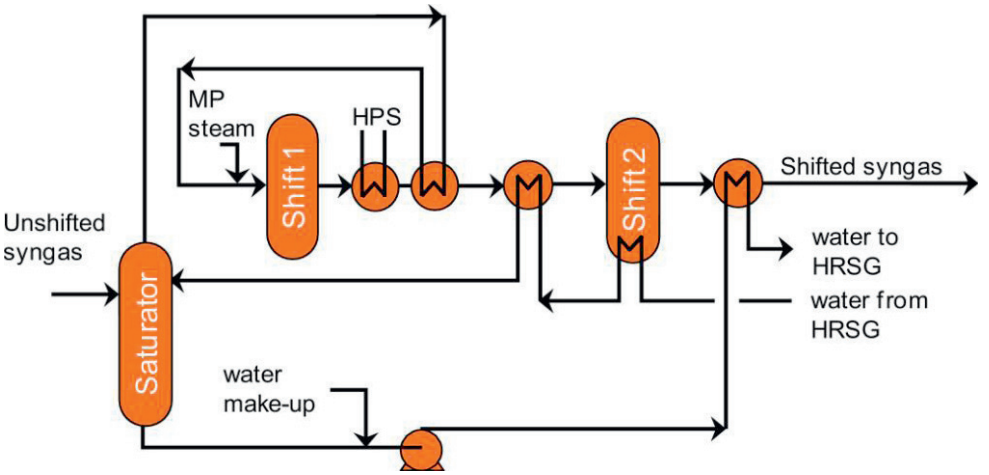

Figure 3: CO Shift Unit

3.3. Sulphur Removal - Thiopaq O&G Technology

The Thiopaq O&G process was originally marketed by Paques to be used solely for the treatment of Biogas, which is produced by anaerobic digestion of waste water. Cooperation with Shell has led to further development of the process and resulted in the Thiopaq O&G process. The technology can be applied at high and low pressure in the natural gas/petrochemical environment at an economic scale for projects up to 150 TPD sulphur removal.

In this IGCC application it replaces the DEPG-based solvent H_2S removal, the Claus sulphur removal unit and the tail gas treating unit of the base case. The process depicted below (Figure 4) consists of three main sections i.e. absorption, reaction and sulphur recovery.

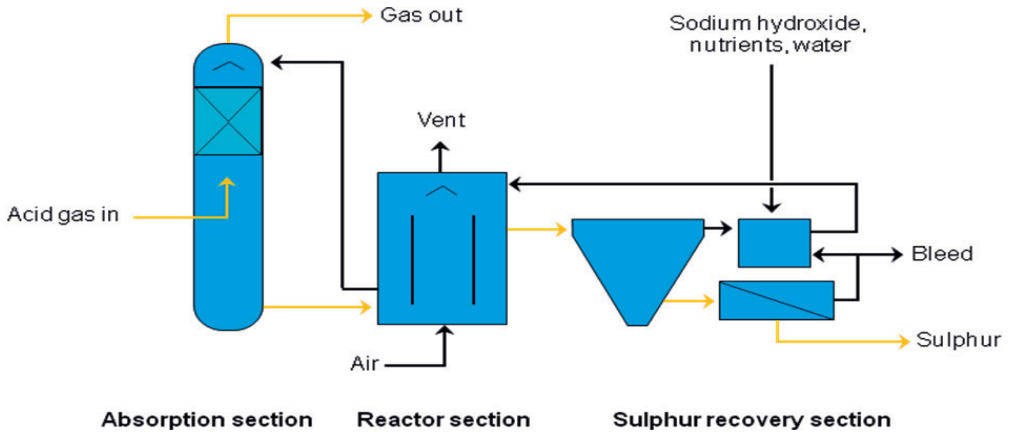

Figure 4: Thiopaq O&G Unit

3.3.1. Process Description

The shifted syngas first comes into contact with the lean solution in the absorber. This solution absorbs the H_2S to form sodium sulphides, and treated syngas exits the absorber. Minor acid gas streams from the gasifier sour slurry stripper and sour water stripper (SWS) are treated in a catalytic HCN hydrolysis unit and a NH_3 scrubbing unit (not shown) before entering the H_2S absorber. This pre-treatment removes HCN and NH_3, which are both poisonous to the bacteria used as a biocatalyst in the Thiopaq O&G process.

The H_2S rich solvent leaving the bottom of the H_2S absorber is let down across a hydraulic turbine and flashed to remove dissolved CO_2. The treated flash gas is used as fuel for the coal drying in the gasification unit, while the rich solvent is fed to the bioreactor for regeneration.

The bioreactor is operated at atmospheric pressure and ambient temperature, and is where the micro-organisms oxidize the sulphide to elemental sulphur. The lean solution is recirculated to the absorber, while part of the lean solution is routed to the sulphur recovery section, in order to remove sulphur from the system.

The produced elemental sulphur is separated from the solvent in the sulphur recovery section. Part of the bio-reactor contents is recycled over the settler to maintain the desired dry solid content in the system. The concentrated slurry is then further processed in a decanter centrifuge or a filter press. The recovered water is recycled back to the process via the bioreactor. A small slipstream of the clear solvent is bled from the system to prevent an accumulation of salts beyond the preferred maximum.

3.3.2. Key differentiators

- Lower CAPEX through a lower equipment count i.e. no requirement for burners and reboilers compared with conventional Claus or Shell Claus Offgas Treating (SCOT)-based processing. The regeneration and sulphur recovery section operates at atmospheric pressure and ambient temperature.
- Lower OPEX through reduced chemical costs (only sodium hydroxide and nutrients).
- Simplicity – Lower operator manning levels. Produced biosulphur is hydrophilic and behaves like a relatively stable suspension without clogging.
- Produced bio-sulphur is the basis for a range of new agricultural products designed to act as (ingredients for) liquid fertilizers and liquid fungicides.
- Safety
  - no free H_2S downstream of the absorber;
  - ambient temperatures for the whole system (solution temperatures of 25 – 40 °C);
  - bioreactor and sulphur recovery at atmospheric pressure.

3.4. CO_2 Removal

The conventional DEPG-based acid gas removal arrangement in the base case requires significant electric power, mainly for solvent pumping, plus thermal energy for solvent regeneration. While it is recognised that these energy requirements in the base case were not optimised, it is thought that CO_2 removal from the H_2S-free product gas from the Thiopaq O&G process could benefit from a different approach, consisting of washing with slightly chilled methanol.

Desulphurised syngas from the Thiopaq O&G unit is cooled against treated syngas and refrigerant before being fed to an absorption column where it is contacted with methanol at approximately 0°C. The methanol absorbs both CO_2 and water from the syngas stream, so the downstream CO_2 dryer in the base case is eliminated. Water vapour in the CO_2 absorber feed can be removed by a conventional methanol prewash. The CO_2-rich solvent is let down across a turbine before being flashed in a number of stages in order to recover the CO_2 and regenerate the solvent. The number and pressure level of these flash stages has been selected in order to maximise CO_2 recovery while minimising the power requirement of the downstream CO_2 compressor, i.e. minimising the mass flow rate of CO_2 passing though the lower pressure stages of the compressor. While this operation is subject to methanol vapour losses in common with the well-known Rectisol® process, it is characterised by a rather low solvent circulation rate, minimal refrigeration load (the system is almost auto-refrigerative) and carbon steel construction.

The process is depicted below in Figure 5.

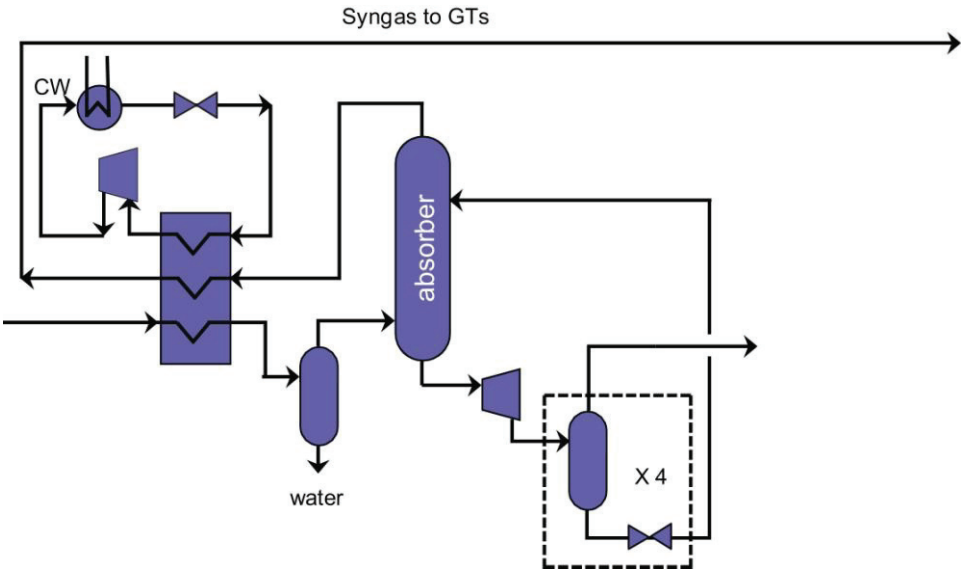

Figure 5: Simplified Representation of the CO_2 Wash Unit

3.5. CO_2 compression and pumping

Foster Wheeler has recently performed a number of studies looking into the optimal method of achieving dry CO_2 at a pressure suitable for transport and storage[2]. This work has shown that the parasitic load associated with this unit is minimised by using a combination of CO_2 compression, liquefaction and pumping, achieving liquefaction at the lowest possible pressure for the available cooling medium.

The base case assumes compression to 150 barg in a seven-stage integrally geared compressor with inter-cooling to 24°C against fresh cooling water. Dehydration is achieved using molecular sieve at a pressure of 47 barg, between the fifth and sixth compression stages.

In the improved case, a six-stage integrally geared compressor with inter-cooling to 24°C against fresh cooling water is assumed with liquefaction at 18°C and 63 barg against sea cooling water. The liquefied

CO_2 is then pumped to supercritical condition at 150 barg. Dehydration is not required in this case, since water has already been removed in the methanol wash unit (Figure 6).

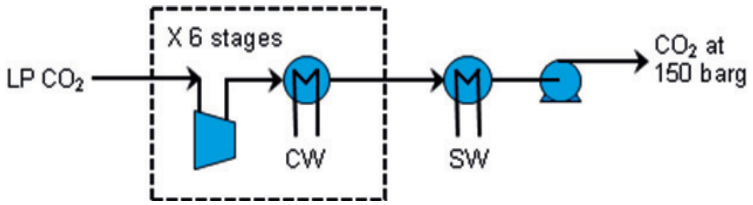

Figure 6: CO_2 Compression & Pumping

3.6. Gas turbine

Potentially there will be significant efficiency gains when improved gas turbine technology for combustion of hydrogen-rich fuel gases becomes available. However, these benefits are outside the practical scope of this paper, due to its emphasis on improvements that are available for immediate implementation.

Gas turbine performance is significantly down-rated in IGCC schemes relative to the performance on natural gas, due to a number of reasons, including lower firing temperatures, lower calorific value of the fuel gas and conservatism in the absence of significant operating experience[1].

A number of gas turbine suppliers have been working to improve the efficiency of their machines for the IGCC application; hence this paper incorporates the some of the latest anticipated performance data from GE, for their Frame 9F Syngas machine (Figure 7).

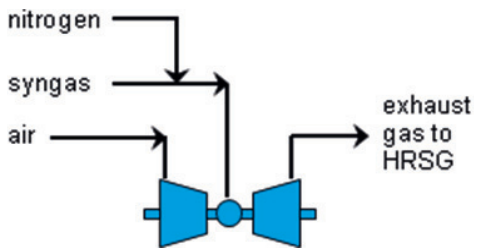

Figure 7: Gas Turbine

It should be noted that if, in the longer term, a gas turbine can be developed to run on hydrogen-rich syngas at an equivalent firing temperature to natural gas fired turbines, then it is anticipated that the efficiency of the overall IGCC scheme, with or without carbon capture, would be increased by as much as four LHV efficiency percentage points[1]. This improvement has not been included in the analysis for this study.

3.7. HRSG & Steam Turbine

The HRSGs receive hot gas from the exhaust of the gas turbines without additional duct firing (post-firing is a useful option for increasing the total power output of a plant, but it slightly decreases the IGCC's overall efficiency).

For this study the HRSGs have been designed for compatibility with the rest of the IGCC scheme, particularly with the steam generation capability of the gasification and isothermal shift unit.

HP, MP and LP steam is generated in each HRSG, with the low pressure steam generation integrated with the BFW deaerator. Steam turbine vacuum condensate plus demineralised make-up water are preheated against the coolest syngas, upstream the Thiopaq O&G unit and is then fed to the deaerator. Deaerated BFW is preheated and fed to the gasification and shift units as well as to supply BFW to the steam generation coils within the HRSGs.

The HRSG layout is conventional, apart from the addition of a saturator water preheat coil, between the LP boiler and deaerator feed heater.

The two lines of GT + HRSG feed steam to a single steam turbine with sea water cooled vacuum condenser.

The arrangement is depicted in Figure 8.

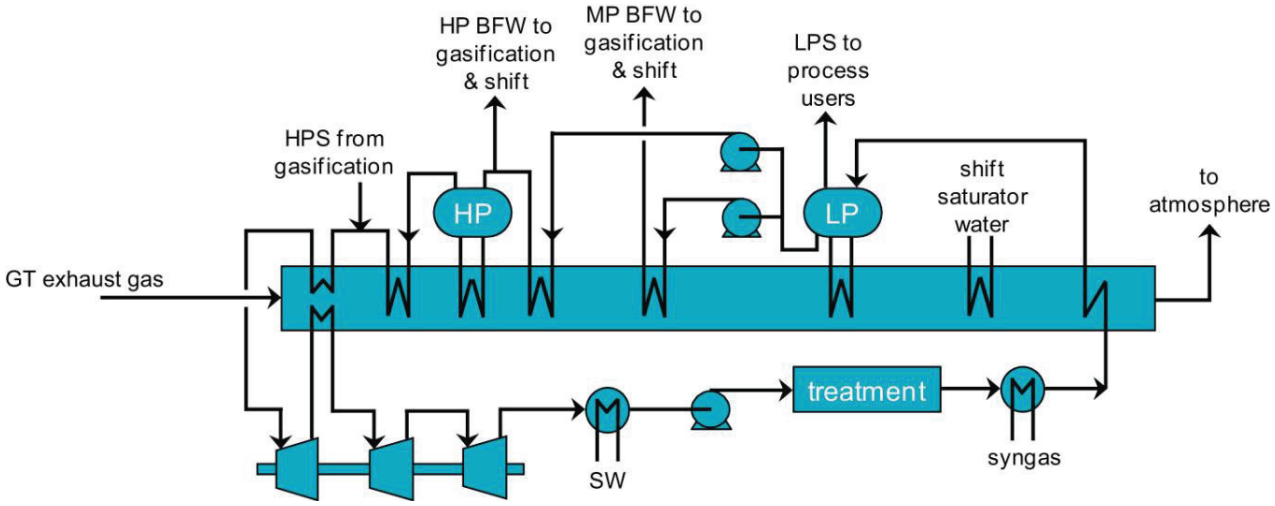

Figure 8: Simplified HRSG and Steam Turbine

4. Overall Results

The process described above was fully simulated using a combination of Aspen HYSYS® and ProMax™ process simulation software. ProMax™ was used for simulation of the methanol wash unit and CO_2 compression, while HYSYS® was used for the rest of the process as shown in Figure 9. Simulating the full IGCC flow scheme in this way enables the different process units and power island to be integrated effectively. The base case was previously simulated by Foster Wheeler in a similar way.

The following figure (Figure 9) and table (Table 2) summarises the key performance figures for both the base case and the improved IGCC flow scheme case.

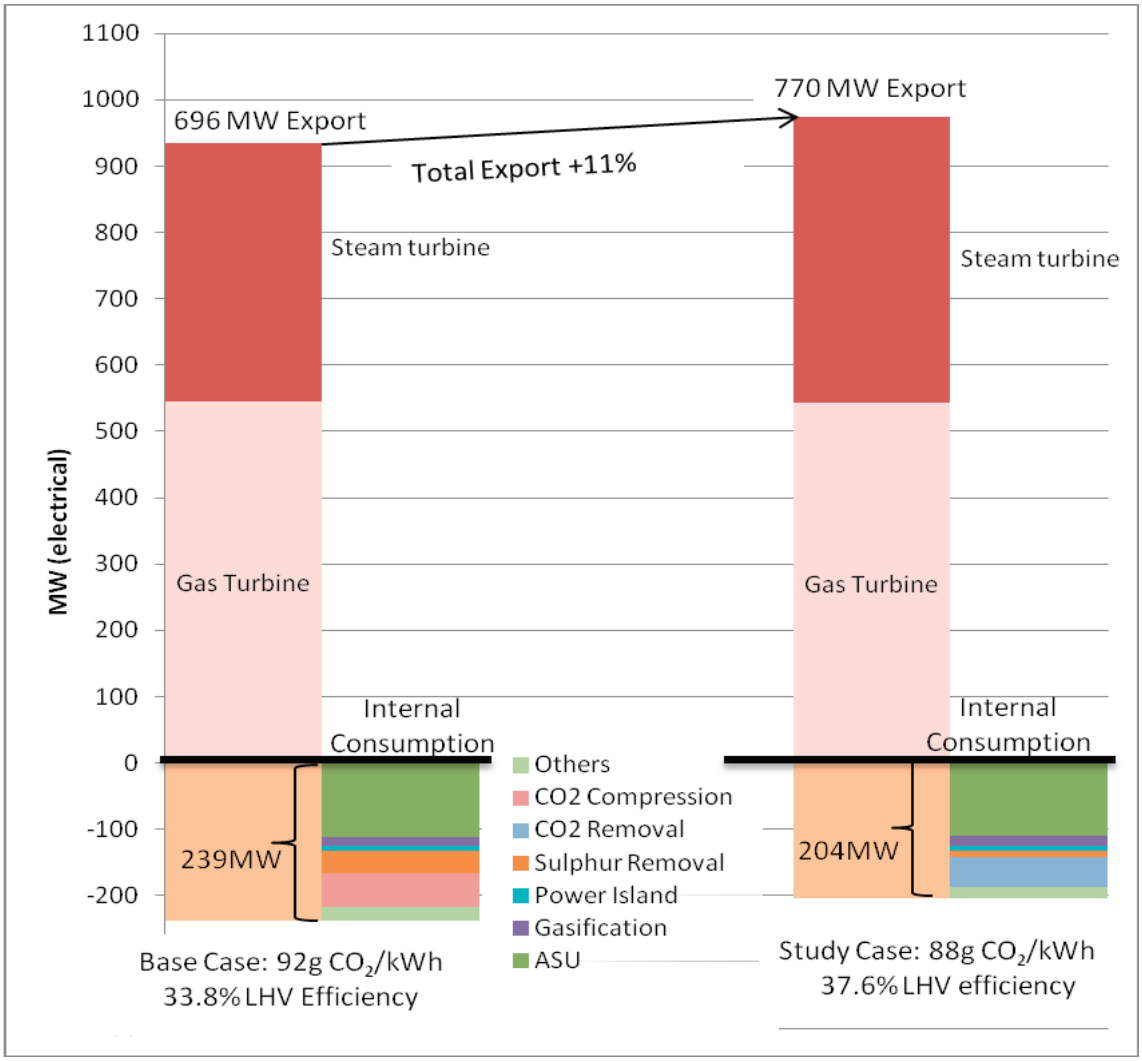

Figure 9: Graphical Results Summary

Table 1: Performance Comparison: Base versus Study Case

		Base Case	Improved IGCC case	Delta
Total gross installed capacity	MWe	934.1	974.5	4.3%
Gas Turbine (s)	MWe	545.1	542.7	-0.4%
Steam Turbine	MWe	389.0	431.8	11.0%
Others	MWe	0.0	0.0	
Total auxiliary loads	MWe	238.6	204.4	-14.3%
ASU	MWe	111.3	111.0	
Gasification / Boiler	MWe	14.2	14.3	
Power Island	MWe	8.0	8.0	
Sulphur Removal	MWe	33.9	8.2	
CO_2 Removal	MWe		45.0	
CO_2 Compression	MWe	49.9		
Others	MWe	21.2	17.9	
Net Power Export	MWe	695.5	770.1	10.7%
Net Efficiency (LHV)	%	33.84	37.62	11.2%
Carbon Balance				
Total carbon in feeds	tpd	4397.8	4416.0	0.4%
Total carbon captured	tpd	3977.9	3972.9	-0.1%
Total CO_2 captured	tpd	14576.7	14558.6	-0.1%
Total carbon emissions	tpd	419.9	443.0	5.5%
Total CO_2 emissions	tpd	1538.8	1623.4	5.5%
Carbon capture rate	%	90.5	90.0	-0.5%
Carbon efficiency	g CO_2/kWh	92.2	87.8	-4.7%

For both cases the throughput of the plant was fixed by ensuring full utilisation of the compressor capacity of the two Frame 7 gas turbines in the power island, hence the coal feed rates and total power production vary slightly.

The following key differences between the performance figures of the two cases can be seen:

- In the improved case less MP steam is required for the CO shift and CO_2 removal processes, leaving more steam available for generation of power in the steam turbine compared with the base case.
- The total parasitic power load for the sulphur removal, CO_2 removal and CO_2 compression processes are significantly lower, in the improved case compared with the base case.

The net impact of these two key differences is to increase the power output of the plant by more than 10% and increase its overall (LHV) efficiency also by over 11%, or 3.8 efficiency percentage points (from 33.8% to 37.6%).

5. Conclusions

The results of this study indicate that there is potential for significant increases, of the order of 10%, in both power output and thermal efficiency of a coal-based IGCC with carbon capture, on the basis of a preselected gas turbine type.

These benefits result from a combination of:

- improved configuration of the CO shift unit, combining improved CO shift catalyst, internally cooled shift reactor design and enhanced preheating of saturator feed water,
- replacement of conventional H_2S removal and Claus sulphur recovery with Thiopaq O&G technology for direct conversion of H_2S to elemental sulphur,
- improvements in physical solvent removal of CO_2 from the CO shift product gas, currently represented by methanol wash at moderate sub-ambient temperature (around 0°C).

Further increases in power output and efficiency are expected in the near future from:

- improved ASU design, reducing power required for oxygen production,
- at least partial integration of the ASU with the gas turbines,
- operation of the gasifiers at lower temperatures,
- increase of the GT firing temperatures for syngas operation closer to those used in natural gas operation.

In the authors' view it would be very desirable if at least one of the IGCC projects now under consideration for the EU NER300 initiative could be used to demonstrate some efficiency-enhancing improvements such as those outlined in this paper. This would help counter a marked tendency for these projects to be limited to technologies already demonstrated at existing IGCC plants due to the perceived risk of new technology.

6. References

[1] S. Ferguson, T. Bullen & G. Skinner, Foster Wheeler, "Opportunities for Efficiency Improvements in Power Plants with Carbon Capture", PowerGen Europe 2010, Amsterdam, June 2010.
[2] T. Bullen & S. Ferguson, Foster Wheeler, "Efficiency improvements in fossil-fired power generation with post-combustion carbon capture via improved heat integration and reuse of low grade heat", PowerGen Europe 2011, Milan, June 2011.